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APPLICATION OF

COLUMBIA GAS OF VIRGINIA, INC.
(Formerly Commonwealth Gas Services, Inc.)

CASE NO. PUE970455

**For a general increase in natural gas rates
and approval of performance-based rate
regulation methodology pursuant to Va.
Code § 56-235.6**

REPORT OF DEBORAH V. ELLENBERG, CHIEF HEARING EXAMINER

November 13, 1998

HISTORY OF THE CASE

On May 9, 1997, Columbia Gas of Virginia, Inc. (formerly Commonwealth Gas Services, Inc. and hereinafter referred to as “Columbia” or the “Company”) filed an application for a general increase in natural gas rates and approval of performance-based rate regulation methodology pursuant to Virginia Code § 56-235.6. On May 20, 1997, Columbia completed its application by filing revisions to its proposed rates and charges and its testimony and exhibits supporting the application. The application actually contained three distinct requests. The first request was for approval of a new pilot transportation program called the “Commonwealth Choice Program.” The application also sought approval of a general rate increase, and approval of a performance plan.

In the application, Columbia sought proposed rates and charges designed to produce \$10,084,956 in additional annual operating revenues effective October 7, 1997. Of that amount the Company believed \$8,539,171 was necessary to recover its cost of service in accordance with the Commission’s Rules Governing Utility Rate Applications and Annual Informational Filings (“Rate Case Rules”), 20 VAC-5-200-30 and Virginia Code §§ 235.2 *et seq.* The remaining \$1,545,785 was to be subject to the performance plan. In addition, the Company sought \$1,894,031 to be effective in 1998 for the twelve months ending September 30, 1999, and \$873,755 to be effective in 1999 for the twelve months ending September 30, 2000. Those increases were also proposed subject to the performance plan.

By letter dated June 13, 1997, the Applicant proposed to bifurcate the Commission’s consideration of the application into Phase I and Phase II. The Company proposed Phase I to address the proposed general rate increase of \$8,539,171 including the Commonwealth Choice Program and proposed that rates designed to recover that additional revenue requirement be placed into effect on October 18, 1997, which was 150 days from the date the application was completed.

In Phase II, the Company suggested that the Commission consider approval of the proposed performance-based form of regulation which was designed to produce annual revenue of \$1,545,785 beginning in October 1997, with additional increases in 1998 and 1999.

On June 19, 1997, Staff filed a Motion for Rulings on Effective Dates of Proposed Rates. Therein, Staff noted that it had no objection to bifurcation of the application into the phases proposed by the Company; however, Staff questioned the Company's proposed effective date of the Commonwealth Choice Program, which was then proposed to be part of Phase I. Staff also asserted that the Commission must address the effective date of the proposed performance plan in Phase II.

The Company responded to Staff's motion and requested the Commission to rule that all of its Phase I increase, including the Commonwealth Choice Program, could become effective after the expiration of the 150 day statutory maximum suspension period; and that the Phase II rates, based on the performance plan, likewise should become effective after the 150 day suspension period. The Division of Consumer Counsel, Office of the Attorney General ("Consumer Counsel") and several protestants also filed responses to Staff's motion. In reply to those parties, the Company requested the Commission to allow the Commonwealth Choice Program to go into effect after notice but before hearing, or alternatively, requested that if a hearing was deemed necessary that it be scheduled no later than early fall.

On July 28, 1997, the Commission issued its Order for Notice and Hearings ("Scheduling Order") in which it bifurcated the proceeding as proposed by the Company. In that order the Commission found that the Commonwealth Choice Program was an experimental pilot program subject to the requirements of Virginia Code § 56-234 and that a hearing should be held forthwith to consider the program. The Commission found that Phase I rates should be suspended for 150 days from May 20, 1997, the date on which the application was completed, with the exception of the rates associated with the Commonwealth Choice Program. The Commission also held that the rates associated with Phase II could not take effect until after a hearing was held on that portion of the case. The Commission scheduled a hearing on the Commonwealth Choice Program for September 17, 1997. It scheduled a hearing before a hearing examiner for February 23, 1998, to hear all evidence relative to Phase I of the application including the stranded cost recovery mechanism proposed in the Commonwealth Choice Program. Finally, the Commission set a hearing on the Company's proposed performance-based ratemaking methodology and rates associated therewith, Phase II, to begin June 16, 1998. The Commission also established procedural schedules for the filing of testimony and exhibits relative to all three hearings.

Proof of publication of the application and the related hearings was received by the Commission at the hearing on the Commonwealth Choice Program on September 17, 1997.

On September 30, 1997, after hearing, the Commission issued an order approving the Commonwealth Choice Program. Therein, the Commission reiterated its finding that the Commonwealth Choice Program was a voluntary rate experiment which could only take effect after notice and hearing as required by Virginia Code § 56-234. The Commonwealth Choice Program included a stranded cost recovery charge ("SCRC") for recovery of stranded costs resulting from the program. In the July 28 Scheduling Order, the Commission had deferred consideration of that charge to the hearing on the general increase in rates, Phase I. In the September 30, 1997 Order, the Commission allowed the Commonwealth Choice Program to take effect as provided therein, but the Commission ordered Columbia to file revised tariff provisions containing the various terms and conditions prescribed in the order and again deferred consideration of the SCRC. The Commission

directed Columbia to file with the Director of Public Utility Accounting a semiannual statement of stranded costs incurred during the program.

On October 17, 1997, the Company filed a bond to place interim rates into effect on October 18, 1997 in accordance with the Commission's July 28 Scheduling Order. By Hearing Examiner Ruling that bond was accepted for filing and the Company was directed to keep accurate records of all amounts received under the proposed rates should the Commission modify or reject the Company's proposed rates.

On December 31, 1997, the Company filed a Motion to Withdraw Performance-Based Ratemaking Aspect of the Case. Thus, the Company proposed to amend its application to eliminate its request for approval of the Phase II rates and to withdraw all testimony and exhibits or portions of testimony and exhibits that were offered in support of the performance plan. By order dated February 9, 1998, the Commission granted the Company's Motion to Withdraw. Hence, only the general rate request, including the SCRC, remained.

Several parties filed notices of intent to participate in this case. The Consumer Counsel; E.I. Du Pont de Nemours & Co., Inc./Conoco, George-Pacific Corporation, Hoechst Celanese Corporation, ICI Americas, Inc., LG&E Power Development Corporation, Owens-Brockway Glass Container, Inc. and Virginia Fibre Corporation (hereinafter "Industrial Protestants"); Westvaco Corporation; Enron Capital & Trade Resources Corp. ("Enron"); and the Board of Supervisors of Fairfax County, Virginia, all filed Notices of Protest. The Board of Supervisors of Fairfax County, Virginia, later withdrew their Notice of Protest by letter dated March 10, 1998.

Discovery ensued, and on January 23, 1998, Staff filed a Special Motion for Ruling on the Validity of Objections raised by Columbia. Specifically, Staff sought information on consolidated federal income tax returns and tax liability for Columbia and its affiliates for 1981 through 1996. The Company generally asserted that the information sought was irrelevant, and requested a hearing on the motion. Oral argument was scheduled, and held on January 28, 1998. By Hearing Examiner's Ruling dated January 28, 1998, Staff's motion was granted and the Company was compelled to produce the tax information requested.

Also on January 28, 1998, the Industrial Protestants filed a Motion for Leave to File Rebuttal Testimony. In support of the motion, their counsel stated that the testimony filed by the Consumer Counsel advocated the adoption of a cost allocation methodology which was in direct conflict with that proposed by the Company and which was not adopted by the Commission in previous proceedings. The Industrial Protestants argued that their testimony and evidence was now vital to establish a complete record upon which the Commission could make its decision on cost allocation in this case. Staff and the Consumer Counsel were provided an opportunity to respond. Staff did not respond, but the Consumer Counsel opposed the motion. By ruling dated February 3, 1998, the motion was granted and the Industrial Protestants were allowed to file direct testimony out of time.

On January 29, 1998, the Company filed a Motion for Protective Order seeking confidential treatment of certain information requested in Staff's interrogatories. On January 30, 1998, a ruling was entered granting the motion for protective order.

The Company next filed a Motion for Extension of Time and Continuance on February 17, 1998. Therein, it asserted that Staff's testimony and exhibits comprised more than two inches of paper, and importantly, recommended that the Commission not grant Columbia any rate increase as a result of numerous and complex accounting adjustments. It alleged that its rates were in effect on an interim basis and subject to refund with interest, and accordingly, a delay would not prejudice any party or harm the public interest. Columbia recommended other related adjustments in the procedural schedule. On February 18, 1998, the Motion for Extension of Time and Continuance was granted, and a revised procedural schedule was established. The public hearing scheduled to be convened on February 23, 1998, was retained to receive comments from public witnesses. The hearing was otherwise rescheduled to begin March 31, 1998.

No public witnesses appeared on February 23, 1998. The public hearing continued on March 31, 1998. Edward L. Flippen, Esquire, Kodwo Ghartey-Tagoe, Esquire, and Mark C. Darrell, Esquire, appeared as counsel for Columbia. Eric M. Page, Esquire, appeared as counsel to Columbia Energy Services Corporation. Thomas B. Nicholson, Esquire, and Amy Hay Schwab, Esquire, appeared on behalf of the Consumer Counsel. Penny Sellers, Esquire, and Louis Monacell, Esquire, appeared on behalf of the Industrial Protestants. Randall S. Rich, Esquire, appeared as counsel to Enron Energy Services, Inc. Wayne N. Smith, Esquire, and C. Meade Browder, Jr., Esquire, appeared as Staff counsel. Scott Camp appeared as a public witness. The hearing continued for three days through April 2, 1998. Transcripts of all hearings are filed with this Report.

Subsequent to the hearing on May 5, 1998, as requested, Staff filed Exhibit RWT-43 which showed Staff's original calculation of an earnings test without a proposed consolidated tax savings adjustment. Simultaneous post-hearing briefs were filed by Staff and all parties on June 4, 1998.

On June 8, 1998, counsel for the Company filed a Motion to Strike a portion of the brief filed by the Industrial Protestants because the Company asserted that the Industrial Protestants had claimed that they would not address revenue requirement. The Industrial Protestants allege in their brief that the Company's requested revenue requirement is excessive, and recommend that the Commission adopt the Staff's recommendations in that regard. By ruling dated June 9, 1998, the Industrial Protestants were provided an opportunity to respond to the Motion to Strike and they filed their opposition to the Motion to Strike thereafter. On June 17, 1998, Columbia withdrew its Motion to Strike.

SUMMARY OF THE RECORD

The Company originally filed an application for a proposed annual increase of \$10,084,956 to be effective October 7, 1997. (Application, Schedule 12). Of that increase, \$8,539,171 was proposed to recover the Company's cost of service for the test year ending December 31, 1996. The remainder was subject to certain proposed performance-based standards set forth in the application. The Commission authorized the Company to withdraw its performance-related proposed increase by the order dated February 9, 1998, thus leaving a general rate case with rates designed to produce an increase of just over \$8.5 million.

There were a number of issues that the parties were able to resolve before the hearing. The Company accepted certain adjustments and updated others proposed by Staff and other parties. By the hearing the Company was requesting a revenue increase of \$7,941,578.

The parties also agreed to the admission of all testimony relating to cost allocation. All parties agreed that if the Commission approves the revenue increase in this case that it should be allocated to customers according to the percentages provided on an exhibit submitted by Company witness Horner. (Ex. REH-27; Attachment 1, Revised; Tr. at 525). The parties agreed that those percentages, which are set forth in Appendix 5 to this report, provide a reasonable basis for allocation. The parties also agreed with Staff witness Lacy's recommendation that the customer charge for the residential class should be proportionately lower and that customer charges should be set in increments no lower than five cents per month for residential customers if the Commission's final decision in this case results in a lower revenue requirement. (Tr. at 426-427).

Many issues affecting the revenue requirement, however, remain in dispute. Those issues affect net operating income, rate base, and the appropriate rate of return. Most notably, the Company opposes Staff's application of an earnings test to write off regulatory assets conceptually, and also the manner it is applied by Staff in this case. The Company also asserts Staff's consolidated tax savings adjustment is unlawful. Those two issues have a significant impact on revenue requirement and are paramount to the Company.

The Company also proposes to use the capital structure of its parent, the Columbia Energy Group ("CEG") adjusted to remove the effects of bankruptcy. Bankruptcy concerns also affect the cost of debt. The Company proposes rates based on a return on common equity of 11%.

The original tariffs in the application also included a charge through which the Company proposed to recover stranded costs resulting from the Commonwealth Choice Program. The Company asserted at the hearing, however, that the Commonwealth Choice Program had not generated sufficient information to adequately address the proposed SCRC mechanism and requested that the Commission defer any ruling on stranded cost recovery until its next case or until the Company applies to make the Commonwealth Choice Program permanent. In the alternative, if the Commission determines it is appropriate to decide the stranded cost issue in this case, the Company seeks recovery of stranded costs from all residential and small general service customers.

The Company offered the direct and/or rebuttal testimony of Arthur J. Riffard, Jenny B. Deegan, James F. Racher, Robert E. Horner, John E. Skirtich, Laura M. Batemen, Dan Furlano, Jeffrey T. Gore, Robert V. Mooney, John R. Blair, Robert L. Hahne, and Dr. James R. Haltiner in support of its application.

Staff filed the testimony of Catharine Milmore Lacy, Lawrence T. Oliver, and Richard W. Taylor in support of its position. Staff supports the application of an earnings test to write off regulatory assets in this case, application of a consolidated tax savings adjustment, numerous other adjustments affecting the revenue requirement, and a return on equity of 10.5%. Notably, Staff's consolidated tax savings adjustment would credit net operating income to reflect the carrying costs of past consolidated tax benefits. (Ex. RWT-35, at 25-32; Ex. RWT-37, Schedule B to Statements II and III, Revised, Page 1 of 2, Adjustment 59). Staff asserts that for years CEG has enjoyed the

benefits of filing consolidated tax returns. Staff attempts to quantify those benefits and develop a mechanism to credit Virginia ratepayers with a fair proportion of the carrying costs of the savings.

Other accounting issues which remained in controversy between the Company and Staff included the allowance for uncollectibles, expenses incurred in Columbia's Common Cents Program and its cooperative advertising expenses, and calculation of rate base. Issues also remain concerning the capital structure and several cost rates for the components of the capital structure. Staff proposes to use a current actual capital structure without adjustment for the bankruptcy. The bankruptcy also affected several decisions on debt refunding and issuances. Staff ultimately recommended an increase in aggregate revenue of \$1,063,731. (Tr. 565). Staff's revenue requirement is based on a return on equity of 10% to 11%, and a rate of return of 8.439% to 8.896%.

Staff also raised several rate design concerns, particularly with the Company's propane service. Staff supports the implementation of the Company's new propane service schedule subject to limiting availability to customers for whom the Company plans to have natural gas available in the near future. Staff also supports closing the existing propane service schedule to new customers, and selecting propane suppliers by competitive bid. (Ex. CML-24, at 10-11).

Addressing the recovery of stranded costs from the Commonwealth Choice Program, Staff asserts it is inappropriate to establish a surcharge while the Company is contracting for additional pipeline capacity. If the Commission implements an SCRC, however, Staff asserts that all customers should not be held liable for the costs of a program which is available only to a few.

The Consumer Counsel offered the testimony of Richard Galligan from Exeter Associates, Inc. Although the Consumer Counsel raised issues regarding cost allocation in filed testimony, he now supports the stipulation of the parties regarding a fair allocation of any revenue requirement. The Consumer Counsel also addressed the recovery of stranded costs associated with the Commonwealth Choice Program. The Consumer Counsel recommends that any such stranded costs should be recovered through a volumetric surcharge assessed on all transportation throughput, and that such costs, if any, should therefore be recovered from all participants in the competitive gas acquisition market. Mr. Galligan further asserts that it is unreasonable to recover any stranded costs from residential and small customers who do not participate in the program because they did not cause and are not responsible for the incurrence of those costs.

The Industrial Protestants filed testimony in the case on cost allocation, revenue apportionment, and stranded costs. They too participated in the agreement and support the cost allocation and revenue apportionment offered by the Company in its rebuttal. Their continuing participation in the case was limited to the issue of stranded costs. They offered the testimony of Alan Phares in support of their positions; however, in order to avoid the travel expenses of Mr. Phares, the Industrial Protestants withdrew that portion of his filed testimony relating to stranded costs and submitted the remainder of his testimony by agreement of counsel. The Industrial Protestants therefore addressed the issue of stranded costs through cross-examination and brief. They assert that the Company has no stranded costs associated with the program and that approval of a mechanism to recover such costs would be premature. If the Commission decides to move forward with a recovery charge mechanism, however, they urge the Commission to approve the

Company's position and to apply the charge only to customers in the residential and small general service classes who are eligible to participate in the program. The Industrial Protestants assert that it would be unfair and unwarranted to apply the charge to transportation customers who have already been participating in the market since the mid 1980s and therefore have not caused any of the alleged stranded costs.

Kathleen Magruder offered testimony on behalf of Enron. Her testimony also focused on the stranded cost issue. She advised that Enron does not object, as a general matter, to stranded cost surcharges provided they take into account all appropriate mitigation measures, including capacity release, accounting for system load growth, off-system sales, and any other appropriate measures. She also supports the Company's proposal to charge any stranded cost recovery to all customers within the residential and commercial classes since the program benefits all those customers. Enron believes that all mitigation efforts should be applied to make net stranded costs as small as possible and therefore avoid the erection of barriers to competition and customer choice. Moreover, Enron asserts that stranded cost recovery charges have a finite end and that the end should be tied to the opening of the entire system or Columbia exiting the merchant function.

Finally, Columbia Energy, an affiliate of the Company, is an unregulated energy marketing subsidiary of the Columbia Energy Group. Columbia Energy offered no witness, but counsel advised that its interests are limited to the proposed stranded cost recovery charge. It asserts that if the Commission allows for such a charge, it should be competitively neutral and the charge should be spread out among all residential and small general customers, not just those who leave the system.

DISCUSSION

NET OPERATING INCOME

1. Earnings Test

a. The Regulatory Assets

The Company has two regulatory assets on its books. The costs of environmental cleanup at Lynchburg, Portsmouth, Petersburg, and Staunton have been deferred and are currently being amortized over a five-year period. (Ex. RWT-35, at 3). Staff updated the actual charges relating to environmental remediation through September 30, 1997, and then subtracted the amortization taken through September 30, 1997.

Costs related to corporate restructuring were also deferred beginning in 1995. By letter dated January 23, 1995, the Director of the Division of Public Utility Accounting for the Commission approved the deferral of those restructuring costs subject to an earnings test and as determined in the context of a rate proceeding. (Ex. RWT-35, at 22; Ex. JFR-59, Attachment 5, at 1). In the Company's last rate case, Staff recommended that the Company defer the costs associated with its restructuring efforts. (Ex. JFR-59, at 5). The Commission approved a rate increase for the Company in that case including Staff's recommendation, by Order Accepting Modified Settlement. (*Application of Commonwealth Gas Services, Inc.*, Case No. PUE950033,

1996 S.C.C. Ann. Rep. at 268). As of September 30, 1997, the Company has deferred \$3,854,847 and is seeking to amortize those costs over three years in this case. (Ex. RWT-35, at 22; Ex. JFR-59, at 6).

Staff witness Taylor testified that there had been significant cost savings which have occurred since the Company implemented its restructuring initiatives. He notes those savings have been in the form of lower payroll and benefit costs due to a smaller workforce. (Ex. RWT-35, at 22). He further notes that most of those savings have occurred since rates from the Company's last case were put into effect and therefore have not been recognized in the ratemaking process. In Staff's opinion, those restructuring savings should be matched against restructuring costs. (*Id.* at 23). Initially, Staff determined that \$2,503,816 in savings had been experienced from October 13, 1995, the date the rates went into effect in Case No. PUE950033, through September 30, 1997. (*Id.*). In supplemental testimony, Mr. Taylor recognized that certain new hires were also the result of restructuring and he adjusted his restructuring savings downward to \$916,026. (Ex. RWT-37, Appendix at 75, Revised). Mr. Taylor then mathematically determined that net restructuring costs were \$2,938,821. (*Id.*).

The Company notes that prior to its last case, it was deferring part and expensing part of its restructuring costs. The Company also notes that some of the restructuring expenses date back to 1994, and expresses concern that it would have expensed them but for the Staff's recommendation in the last case that they be deferred. The Company charges that the "assumed savings" from restructuring, like the consolidated tax savings adjustment, attempts to change elements of the past cost of service retroactively. It charges that offsetting costs with savings constitutes retroactive ratemaking since it requires the write-off of assets with earnings from past periods. (Ex. JFR-59, at 6).

I disagree with the Company. Savings from restructuring should be netted against costs. Increases and decreases (or savings) in costs should always be considered. I view this much differently than the consolidated tax savings adjustment. The restructuring costs have been deferred, and are now being considered for inclusion in future rates. The offsetting savings for the same period should similarly be considered to balance the interests of the Company and its ratepayers.

b. Use of the Earnings Test

Staff performed an earnings test based on actual earnings, average rate base and capital structure to determine the appropriateness of establishing a regulatory asset and the continued amortization of an existing regulatory asset. Staff made limited adjustments, but unlike typical rate case adjustments intended to establish a revenue requirement going forward, Staff's adjustments were intended to place the per books financial data of the Company on a ratemaking basis. According to Staff's earnings test, the Company earned a return on equity of 12.13% after limited adjustments and based on actual weather. The current authorized range of return on equity is 10.10% to 11.10%. Therefore, based on the results of its test, Staff proposed that amortization of restructuring costs should be discontinued. Staff also recommended that the amount of the amortization of environmental cleanup costs be significantly reduced. Thus, the Staff found that

\$3,214,657 of existing and new regulatory assets had already been recovered and need not be included in future rates. (Ex. RWT-37, Statement VII, Revised).

The Company argues that the earnings test is unlawful, and further, that Staff's earnings test incorporates more than "limited" adjustments. Although the use and the specific manner of applying the earnings test were hotly contested, the appropriateness of the use of an earnings test has since been decided by the Commission. The Commission has held that "[a]n earnings test is applied to earnings results within a test period. No refund of revenues previously collected occurs as a result of the application of an earnings test. Rather the purpose of an earnings test is to evaluate whether regulatory assets on the utility's books during the test period have been recovered more quickly than anticipated or whether they should continue to be deferred and amortized."

Application of Roanoke Gas Company for an annual informational filing and Application of Roanoke Gas Company for expedited rate relief, Case Nos. PUE960102 and PUE960304, Final Order at 6-7 (August 6, 1998) (Hereinafter "Roanoke Order").

The Commission has also held that a regulatory asset:

[i]s a deferral of a current period cost amortized over future periods. Such costs are generally large and nonrecurring and cause financial results to be negatively affected when currently expensed. This deferred treatment of current charges is unique to regulated entities. Unregulated entities under Generally Accepted Accounting Principles would expense the charges in the period incurred. By permitting a regulated public utility to defer these charges, the utility is afforded an opportunity to recover them over future periods. A utility's shareholders benefit from the original deferral of charges associated with regulatory assets because the deferral increases earnings above what they would have been had there been no deferral.

An earnings test has been used to determine whether regulatory assets have been recovered more quickly than anticipated or whether they should continue to be deferred and amortized. The earnings test has been employed in other cases to evaluate the test period recovery of a number of regulatory assets, including other post employment benefits ("OPEB") implementation costs, electric capacity contract charges, and extraordinary storm damage costs. . . rate case expenses, cost of a depreciation study, franchise costs, Liquefied Natural Gas ("LNG") tank painting costs, union contract negotiation costs, and demolition costs related to a retired manufacturing gas plant.

Application of Washington Gas Light Company, Virginia Division, for an annual informational filing, Case No. PUE970328, Final Order at 4-5 (August 6, 1998).

An earnings test does not result in a retroactive adjustment to rates. It simply assesses whether the amortization of regulatory assets should continue prospectively. The Commission has clearly found use of an earnings test a proper analysis to judge whether regulatory assets should continue to be amortized prospectively.

c. Limited Adjustments

In this case, the Company also contests the manner in which Staff has applied the earnings test. The Company argues that Staff erred in making a consolidated tax savings adjustment (“CTS”) that inflates revenues, yet Staff excludes a weather normalization adjustment in the earnings test. The Company asserts that the CTS proposed in this case is a forward-looking ratemaking adjustment that was neither considered nor approved in the last case. The adjustment imputes over \$1 million to Columbia based on consolidated tax savings from the years 1981 through 1996. (Tr. 739-40). The Company asserts that inclusion of the CTS in the earnings test is improper ratemaking and fundamentally unfair. The Company observed that if you exclude Staff’s proposed CTS from the limited adjustments made prior to applying the earnings test, the test yields a return on common equity during the test year within the authorized range. (Ex. RWT-43).

The Commission has held that “in conducting the earnings test, only limited adjustments should be made to the Company’s books to restate GAAP to regulatory accounting.” *Application of Appalachian Power Company*, Case No. PUE940063, 1996 S.C.C. Ann. Rep. 255, 257; *Application of Virginia Electric and Power Company*, Case No. PUE880014, 1988 S.C.C. Ann. Rep. 312. Here, the CTS is a new adjustment proposed and at issue in this case, not previously approved. “Limited” adjustments should only be those necessary to place the utility’s per books financial data on a ratemaking basis. Staff’s CTS is intended to capture consolidated tax benefits, and does not appear to meet the Commission’s definition of “limited,” but more importantly, as discussed below, I agree with the Company that the CTS should be rejected on its merits. Certainly, if the adjustment is rejected for future ratemaking it should not be allowed as a limited adjustment in the earnings test.

The Company also disputes exclusion of a weather normalization adjustment. Addressing weather normalization in the earnings test, however, the Commission held that:

[T]he purpose of an earnings test is to review test period results to determine whether deferred costs were actually recovered more quickly than anticipated. Accordingly, the per books results of the earnings test should not be weather normalized. Instead an earnings test employs per books data for a test period, based on average rate base and investment. Typical adjustments used in an earnings test are those necessary to restate per books results to a regulatory basis, such as adjustments to correct booking errors and inclusion of JDC capital expense and associated tax savings. Removal of out-of-period expense items are made only in limited circumstances and include adjustments necessary to true up a gas utility’s purchase gas adjustment or to reverse the effect of an out-of-period base rate refund. Therefore, we agree with the Chief Hearing Examiner that no adjustment for weather should be made to per books results for an earnings test.

Roanoke Order at 8-9.

A weather adjustment is appropriate for setting rates for the future because of unknown variations in the weather, but there is no need to make such an adjustment when reviewing historic earnings. In fact, weather normalizing could distort actual earnings for the test period.

An earnings test incorporating Staff's revisions in Mr. Taylor's supplemental testimony without the CTS is attached hereto as Appendix 1. It shows test period earnings on equity of 10.99%. That is within, but not at the bottom of, the Company's authorized range of 10.10% to 11.10%.

d. Point in the Equity Range

Staff proposes that regulatory assets should be written off to the bottom of the authorized range. The Company asserts that write-off of regulatory assets to the bottom of the range is not appropriate.

The Commission has also addressed that issue.

The next issue we must address is whether, in applying the earnings test to previously approved deferred expenses, the benchmark is the top or bottom of the range or a point within the range. This question flows from the Appalachian Power case we decided in 1996. In that case we held that in establishing the amount of a deferrable expense for ratemaking, we would apply an earnings test such that the expense was deemed recovered to the extent it could be expensed and the company's return on equity was equal to or greater than the bottom of the allowed range of return on equity.

....

[W]e decline to adopt the Hearing Examiner's 'newly created/ previously approved' distinction for regulatory assets, but observed that the APCO case cited by the Examiner would not have demanded a different result in this case had a distinction between the old and new regulatory assets been applied. We find that no distinction should be made between previously approved and newly created regulatory assets for the purposes of an earnings test. In our view, the principle of cost recovery should not change depending on whether a regulatory asset is newly created or already exists.

Roanoke Order at 10-11.

The Commission went on to remind us that:

[D]eferral of costs and creation of regulatory assets have benefited Roanoke. A regulatory asset is a current charge that has been deferred with permission from a regulatory authority to be amortized over future

periods. Such costs are generally large and nonrecurring and may cause a utility's financial results to be materially and negatively affected when they are currently expensed. By permitting a regulated public utility to defer costs, the utility is afforded an opportunity to recover these costs over future periods. Shareholders benefit from the original deferral of the charges associated with regulatory assets because the deferral increases earnings above what they would have been had no deferral been allowed and the costs expensed. The earnings test simply measures, period to period, whether deferred expenses have been actually recovered more quickly than originally anticipated or whether they should continue to be deferred and amortized. The test is the same used to establish the original amount of the deferral and is fair to both shareholders and ratepayers. If the Company wishes to avoid the earnings test, it need not request and should object to, any proposed deferral of large nonrecurring expenses.

Id. at 12-13.

The Company and its shareholders benefited because deferral of the recognition of the restructuring costs and environmental cleanup costs allowed the Company to report higher earnings during the deferral period. (Tr. 863). Based on the Commission's decisions on application of the earnings test and elimination of the CTS from the limited adjustments made to restate the Company's books to a ratemaking basis, I find that a portion of the restructuring costs, \$1,412,308, were recovered during the test period, and therefore, should be written off. A regulatory asset for the balance, \$1,526,513, should be established and deferred over three years subject to review in future earnings tests. The environmental remediation costs as updated by Mr. Taylor should continue to be booked as a regulatory asset.

2. Consolidated Tax Savings Adjustment

One of the single most controversial proposals in this case was a consolidated tax savings adjustment recommended by Staff witness Richard Taylor. That adjustment credits net operating income with the carrying costs of past consolidated tax benefits.

CEG has thirty-four regulated and unregulated subsidiaries including the Company. (Ex. RWT-35, Appendix at 79; RWT-40). Mr. Taylor testified that several CEG subsidiaries generate tax losses nearly every year. On a stand-alone basis those entities would not be able to realize the benefits of the tax losses without the taxable income of the other subsidiaries including the Company. Therefore, the loss affiliates benefit from the ability to realize the tax benefits of a loss in the current year without waiting for a future period in which they might earn taxable income. Thus, Mr. Taylor notes that the taxable income of Columbia has contributed to the consolidated group's ability to currently realize tax benefits. He asserts that since Columbia ratepayers have funded the taxable income, they deserve to earn a return on the benefit that they have provided. Mr. Taylor acknowledges that it is appropriate for the loss subsidiaries to retain the tax benefit of their loss. Staff's adjustment simply recognizes the time value of the benefit that Columbia ratepayers provided. (Ex. RWT-35, at 26).

Staff reviewed consolidated tax records from 1981 to the present and calculated each affiliate entity's tax liability on a stand-alone basis for each year. Stand-alone net operating loss ("NOL") deductions were used to offset each subsidiary's taxable income during three-year carryback and fifteen-year carryover periods, if taxable income existed. Mr. Taylor reasoned that any NOLs remaining could not have been utilized without the operating subsidiaries' taxable income. Thus, the remaining NOLs represented consolidated tax savings. (Ex. RWT-35, at 28). Several modifications were necessary because of aberrations. The consolidated group experienced NOLs in several years, and further, the carryback of the 1995 consolidated NOL created an alternative minimum tax liability in the years 1992 through 1994. (*Id.*). Another modification was necessary because of specific deductions detailed by Mr. Taylor and taken in most of the years which he examined. (*Id.* at 29). The cumulative tax savings were \$14,002,972 as detailed in Mr. Taylor's supplemental testimony. (Ex. RWT-40 Confidential).

The consolidated tax savings were allocated on a pro rata basis to the subsidiaries that generated tax liabilities for those years. The cumulative tax benefit allocated to Columbia was totaled for the years 1981 through 1996. That cumulative allocated benefit was then multiplied by a jurisdictional factor to determine the benefit funded by Virginia jurisdictional ratepayers. (Ex. RWT-35, at 30). An after-tax cost of capital based on the capital structure and costs of debt and equity proposed by Staff witness Oliver was then applied to the cumulative allocated savings to arrive at the time value of those savings and the adjustment for the test year. (Ex. RWT-37, Appendix at 78 Revised; Ex. RWT-40 Confidential; Tr. 740). Staff does not propose modification or amendment of any federal income tax returns or any financial statements for the past periods examined.

Staff initially imputed additional operating income from the proposed CTS in the amount of \$1,586,084. (Ex. RWT-35, Statement II). In supplemental testimony, Mr. Taylor applied an after-tax cost of capital rate of 7.38% to the cumulative tax savings and imputed an annual income stream of \$1,018,511. (Ex. RWT-37; Tr. 733, 740).

The Company first argues that Staff's proposal violates a long-standing policy and cites several cases in which the Commission has affirmed its policy to establish jurisdictional stand-alone taxes. *Application of Virginia Electric and Power Company*, Case No. 19027, 1972 S.C.C. Ann. Rep. 56; *Application of General Telephone Company of the Southeast*, Case No. 19052, 1972 S.C.C. Ann. Rep. 107. In the *General Telephone Company* case, the Commission rejected a consolidated tax adjustment stating:

The fundamental requirement of separation of property, expenses and income between jurisdictional and nonjurisdictional property, expenses and income collapses if some items of nonjurisdictional property, expenses or income are added to or subtracted from jurisdictional items. . . .

The only way to treat a utility business as an island by itself is to insulate it from outside nonjurisdictional property, expenses and income. . . . The fact that the group can deduct from gross income the losses incurred by other subsidiaries does not diminish the amount of gross income contributed by this subsidiary; and we have decided to treat this subsidiary as a

jurisdictional unit, and to allow as an operating expense its tax at the [statutory] rate of 48% of its income.

General Telephone, supra at 113.

The Commission recently reaffirmed its application of the policy that federal income tax expense should be calculated on a stand-alone basis for ratemaking purposes. In *Application of Virginia Suburban Water Company*, Case No. PUE890082, 1991 S.C.C. Ann. Rep. 267 at 268, the Commission held that: “Our policy relevant to calculating FIT expense on a stand-alone basis has been reinforced by decisions in recent Commission proceedings.”

Staff, however, continues to propose stand-alone tax treatment in this proceeding. (Ex. RWT-37, Schedule A to Statements II and III Revised, Adjustment 26; Schedule B to Statements II and III Revised, Adjustment 58; Appendix at 58-59 Revised). Staff agrees, as the Commission has stated that, “the tax on income should be included in the expense of that department of the utility which gave rise to the tax.” *Application of Virginia Electric and Power Company*, Case No. 19342, 1974 S.C.C. Ann. Rep. 212, 222. Staff repeatedly notes that its CTS operates independently of the determination of stand-alone tax liability, and emphasized that it seeks only to credit ratepayers with the carrying costs of the consolidated tax benefits. Staff does not propose a consolidated tax adjustment.

The Company also argues that Staff’s proposal constitutes retroactive ratemaking. The Company acknowledges that Staff may propose that the Commission change its past policies prospectively, but here, Staff begins its calculations with tax losses in the year 1981, fifteen years before the test year.

Staff counters that the adjustment merely allocates an annual pro forma return on the cumulative savings that existed at the end of the test year. Staff asserts that since it neither proposes to redetermine rates for the past at a different level from those charged or go back to order refunds of revenues collected under rates then legally in effect, its CTS does not constitute retroactive ratemaking. Staff argues that it simply uses information from prior periods to develop an adjustment for making rates in the future without impacting rates previously in effect.

The Company further asserts that it is improper to allocate nonjurisdictional tax losses to jurisdictional tax liability. (Brief at 19). It notes that Va. Code § 56-235.2 provides that rates shall be considered just and reasonable only if a utility demonstrates that its rates in the aggregate provide revenues not in excess of the aggregate actual costs incurred in serving customers “within the jurisdiction of the Commission.” The Company also points to the Supreme Court decision in *Commonwealth v. Virginia Electric and Power Company*, 211 Va. 758, 766 (1971), where the Court held that the Commission should fix rates to be charged jurisdictional customers in relation to the cost of serving them.

The Company next argues that the adjustment is contrary to the intent of Congress in establishing tax incentives to encourage investors to take the risks of investing in new plant. (Ex. RLH-46, at 8-9; Tr. 734). Staff counters that it does not question the Company’s right to a tax

credit or tax deduction, but simply attempts to secure for Virginia ratepayers a return on the benefit provided by their income stream. (Tr. 735).

Finally, the Company asserts that federal bankruptcy law precludes the Staff's CTS adjustment. (Tr. at 747-48, 755-56, 779-80; Ex. RLH-46, at 16-17). Company witness Hahne detailed approximately \$2 billion paid relative to bankruptcy claims. (Id.). Mr. Taylor acknowledges that at least \$1 billion in losses in 1995 resulted from the bankruptcy settlement. (Ex. RLH-46, at 16; Tr. 743). That loss produced a tax loss of approximately \$362 million in 1995 which was allocated in part back to 1994 by Mr. Taylor. (Tr. 743-44). Thus almost half of the fifteen year accumulated tax savings on losses arises from the bankruptcy.

Moreover, in 1995, CEG (then the Columbia Gas System) and its subsidiary, Columbia Gas Transmission Corporation ("TCO") executed a bankruptcy disclosure statement. That disclosure statement to creditors advised that the CEG subsidiaries had executed an agreement to authorize their common parent to execute and file consolidated federal income tax returns. (Ex. AJR-13; Ex. RWT-45, at IX-3). The statement, upon which the creditors relied, stated that the consolidated tax agreement ("TAA") would:

enable TCO and TCO's Creditors to benefit from the substantial anticipated tax deduction for payments to Creditors under the Plan, particularly with respect to the Producer Contract Rejection Claims. This tax deduction is expected to produce a substantial reduction in tax and/or a tax refund to the Columbia Group and, under the TAA, the amount of the refund (or an equivalent amount of reimbursement from other members of the Columbia Group) will be paid to TCO. The amount of this anticipated tax reduction/refund has been taken into account by Columbia in valuing the TCO business for purposes of determining the level of distributions that Columbia was willing to guarantee under the Plan, and thereby has increased the amount of distributions that will be made to TCO's Creditors. In addition, certain of the IRS adjustments giving rise to the allowed portion of the IRS Claim result in offsetting favorable adjustments in future years and, as a result of the TAA, the benefit of these favorable adjustments has similarly been taken into account in valuing the TCO business. Accordingly, both TCO and its Creditors will derive significant benefits by the assumption (or enforcement) of the TAA.

Ex. RWT-45, at IX-3.

Thus those tax benefits were considered in determining the payments TCO agreed to make to its creditors in settlement of bankruptcy claims. (Tr. at 660). Staff, however, continues to argue that the bankruptcy settlement does not eliminate the benefit provided by Virginia ratepayers to CEG. (Tr. at 756).

The CTS proposed by Staff in this case is troubling for several reasons. I share the Company's concern with retroactive ratemaking. The Commission has recently addressed charges

of retroactive ratemaking when it affirmed the use of an earnings test to evaluate the recovery of regulatory assets. Since the earnings test was applied to earnings results within the test period for the case, and no refund of revenues previously collected occurred as a result of the application of the test, that analysis did not constitute retroactive ratemaking. *Application of Roanoke Gas Company for an annual informational filing* and *Application of Roanoke Gas Company for expedited rate relief*, Case Nos. PUE960102 and PUE960304, Final Order (August 6, 1998); *Application of Washington Gas Light Company, Virginia Division, for an annual informational filing*, Case No. PUE970328, Final Order at 5-6 (August 6, 1998).

Unlike application of an earnings test that considers earnings from the test period used to make rates in a particular case, the CTS considers transactions occurring fifteen years before the test period. It is true that Staff does not propose to adjust past rates or make refunds; however, Staff does propose to impute income from the benefits of filing consolidated tax returns long before the test period or rate year in this case, and thereby lower current rates.

The Virginia Supreme Court has addressed retroactive ratemaking and held that:

The Commission does not have the power to redetermine rates from a past period at a different level from those actually charged in accordance with filed schedules because that would be to make retroactive rates. (citations omitted).

City of Norfolk v. Virginia Electric and Power Company, 197 Va. 505, 516 (1955).

The Court later reaffirmed its view of retroactive ratemaking:

That concept concerns the attempt to go back in time to order refunds of revenues collected under rates that were legally in effect at the time the revenues were collected. (citations omitted).

Commonwealth Gas Pipeline Corporation v. Anheuser-Busch Companies, Inc., 233 Va. 396, 402 (1987).

Although not characterized by the Court as retroactive ratemaking, the Supreme Court rejected an adjustment to reduce a telephone company's rate base to reflect a large excess profit realized over a ten-year period by an affiliated service company from its dealings with the telephone company. The adjustment had been based on a Staff determination that prices paid over the ten-year period were unreasonable, and the rate base was reduced for making future rates. The Commission did not adjust past rates or order refunds. The Supreme Court in that case, however, held:

We agree with Commissioner Bradshaw's dissent that the Commission acted erroneously when it reduced Central's rate base to reflect alleged excess profits realized over a ten-year period by Service Company from its dealings with Central. We do not question the duty of the Commission to determine what expenditures by a telephone company

for equipment are reasonable, and in so doing to determine if an affiliate supplier's profit margin is excessive or that the prices charged are higher than those charged by a competing supply company. However, the adjustment made was not indicated under the circumstances existing in the case under review.

Central Telephone Company v. State Corporation Commission, 219 Va. 863, 880-81 (1979).

In this case Staff has proposed virtually the same adjustment. In *Central Telephone* Staff reduced rate base, which after applying the cost of capital, reduced revenue requirement by the carrying charges associated with its proposed adjustments. In this case, Staff skips the intermediate adjustment to rate base but instead directly reduces revenue requirement by the carrying charges associated with its consolidated tax savings adjustment.

Of greater concern, Staff's proposal goes back in time to capture benefits that existed prior to the bankruptcy settlement. The settlement statement referred to the consolidated tax savings and relied on them as a resource that could be used to make payments to certain debtors. Thus any income that may have existed from the consolidated savings has been utilized for other purposes and no longer exists. Indeed, CEG and Columbia should be able to move forward without fear of the Commission looking back to financial transactions occurring in the distant past. Accordingly, Staff's attempt to capture benefits which accrued well before the test year is improper.

3. **Uncollectible Expense**

Staff witness Taylor testified that over the past five years the Company's net charge-off rate has been increasing dramatically. Mr. Taylor notes that in 1992, the Company's net charge-off rate was approximately .3%. In the test year, that rate was nearly 1%. Mr. Taylor believes that the increase in the rate is the result of several causes. First, in 1993, the Company suspended the requirement for security deposits, thus final bills could not be reduced by existing security deposits. Second, Staff notes that Citizens Energy, a program designed to assist low income ratepayers with their bills, contributed nothing to the Company between 1993 and 1996. Third, a federal program designed to assist low income ratepayers with their bills reduced its contributions to the Company between 1992 and 1996. Also, in 1995, the Company revised its credit requirements for delinquent customers which reduced the number of shut-off notices, but increased delinquent receivables.

In 1997, the Company took several steps to reduce the net charge-off rate. Those steps included reestablishing the security deposit policy, tightening its shut-off order criteria, lowering its arrears limit and reducing the number of months in arrears before shut-off notices are sent, implementing three new programs, and hiring two additional field collectors. As a result of those measures, pro forma data indicated that the elevated net charge-off rate experienced in the test year should not be experienced in the future. Staff therefore did not consider the test year experience in the three-year average of net charge-offs utilized to calculate the pro forma uncollectible expense. Staff's three-year average net charge-off rate is .6396%.

The Company used a five-year average including the test year experience. Its rate was .736%. (Ex. RWT-35, at 11-13). Company witness Racher testified that the Company's actual

charge-off rate for the test period, the twelve months ending December 31, 1996, was .9430%, more than 20 basis points higher than a five-year average. He does not dispute Mr. Taylor's testimony identifying the changes in the Company's deposit and credit policies. (Ex. JFR-59, at 7-8).

The Commission has approved a five-year average in past cases. Although the Company's improvements are undisputed and should have a positive effect on the charge-off rate, there is no evidence that the changes will result in an immediate and dramatic drop. A five-year average should continue to be used.

4. Office Furniture Expense

Staff proposes to eliminate \$63,416 in expenses for new furniture and \$23,372 in expenses for relocating telecommunications equipment, and instead to capitalize those items. Staff witness Taylor adjusted for the jurisdictional factor, to reduce test year expenses by \$83,503 and increase rate base by the same amount. (Ex. RWT-37, Schedule A to Statements II and III, Adjustment 21). The Company notes that over 410 separate items make up the total expense for new furniture, and Mr. Taylor admits that no single item costs more than \$500. (Tr. 655). Staff, however, asserts that in the aggregate the items are material. The Company counters that in the aggregate, any group of items can become material. (Brief at 28). I agree, certainly material additions to plant should be capitalized, but it is reasonable to have an ongoing expense level for office furnishings, replacement and relocation.

5. Competitive Charges

Staff proposed to eliminate \$97,651 of charges related to competitive activities. (Ex. RWT-35, at 18). Specifically, Mr. Taylor testified that services, including combustion adjustments on appliances and flue inspections on space heating equipment were provided to consumers at no charge. (*Id.*). Mr. Taylor testified that since the services are available from any gas service contractor and are competitive in nature, they should be booked below the line and not included in the Company's cost of service.

The Company agreed that the costs associated with those types of services should be booked below the line and not included in the cost of service. (Ex. JFR-59, at 8). However, Company witness Racher testified that the account in question, Account 879, Activity 3311, also includes the costs of services that are properly recovered in rates. (*Id.*). For example, Mr. Racher testified that expenses also include the cost of converting metered propane service ("MPS") customers from propane to natural gas service. (*Id.*). Expenses for that service constitute \$30,314 of the total. The total also includes costs associated with the installation of equipment such as devices for hearing and visually impaired customers that are part of the Company's tariffed services. That service expense amounts to \$3,099 and also should be recoverable in the Company's cost of service. (*Id.* at 9).

Since the Company has identified two tariffed services recorded in the account, the expenses associated therewith, \$33,413, should be included in the Company's cost of service.

6. Cooperative Advertising Expenses

Staff witness Taylor also recommended disallowing expenses for cooperative advertising incurred during the test year. Those expenses included cooperative advertising with builders and/or developers which fall under the Energy Efficient Home (“EEH”) program, and with contractors included in the Qualified Gas Contractor (“QGC”) program. Staff reviewed representative advertisements. Staff found relatively little information on conservation. Staff witness Taylor testified that only a small part of the contribution by the Company, if any, supported conservation or informational advertising. He noted that in almost all cases the only information in the advertisement was the EEH logo with the following words in small print: “These homes are equipped with Energy Efficient natural gas appliances, saving both money and energy.” (Ex. RWT-35, at 17). Thus, in Mr. Taylor’s opinion, the primary purpose of the ads appeared to be the sale of the home itself. He testified that such advertising promotes load growth which does not meet the requirement of the Commission’s policy on promotional allowances.

The Company argues that the Commission has not banned cooperative advertising. *Commonwealth of Virginia ex rel., SCC ex parte: In re, Investigation of Conservation and Load Management Programs*, 1992 S.C.C. Ann. Rep. 261. To the contrary, the Commission stated that it has and will continue to allow recovery of “reasonable levels of advertising expenses associated with CLM.” (*Id.* at 264). The Company observed that to be recoverable, expenses for cooperative advertising simply must promote the public interest, conservation or more efficient use of energy. Company witness Blair argues that the Company’s advertising promotes the use of more efficient equipment rather than simply the use of gas. (Ex. JRB-60, at 3-7). He offered six pages of advertisements funded by the cooperative program in support of his position. (Ex. JRB-61).

The Company asserts that it does not sell homes or appliances. (Tr. 871). It argues that its joint advertising with home builders and developers and appliance contractors is solely intended to promote the sale of energy efficient homes and appliances and thereby promote conservation and an efficient use of energy. It argues that its cooperative advertising program is an educational and informational tool and enables the Company to reach more customers than its advertising budget would otherwise allow. Moreover, Company witness Blair testified that some of the advertisements describe the benefits of high efficiency equipment in lettering just as large as the rest of the ad. (Tr. 874; Ex. JRB-61).

Earlier this year, the Commission issued an order in which it addressed expenses related to an energy efficient home and qualified gas contractor program for another gas utility. *Application of Virginia Natural Gas, Inc., for an expedited increase in gas rates*, Case No. PUE960227, Final Order (April 27, 1998). In that case, the company urged the Commission to include expenses related to those programs. Virginia Natural Gas Co., Inc. even offered cost/benefit analyses in support of its expenses. The Commission, however, reviewed the ads offered as typical of the EEH and QGC programs and found that:

Based on the record herein, we conclude that VNG’s advertising expenses for the EEH and QGC programs do not comply with the requirements of § 56-235.2 of the Code of Virginia or our Rules Governing Utility Promotional Allowances adopted in Case No. PUE900070. The

advertisements associated with these programs are not required by ‘law or rule or regulation’ nor do they ‘solely promote the public interest, conservation, or more efficient use of energy; . . .’ As we noted in our 1992 Order adopting Rules Governing Utility Promotional Allowances, ‘The Virginia Code prohibits rate recovery for electric utilities for advertising unless it is required by ‘law or rule or regulation, or for advertisements which solely promote the public interest, conservation or more efficient use of energy . . .’ Va. Code § 56-235.2. Accordingly, the Commission has allowed reasonable levels of advertising expenses associated with CLM. Such practice will continue, but we will more closely scrutinize those costs in the context of individual rate cases, to carefully distinguish between advertising for cost effective CLM programs and those primarily designed to promote load growth which do not otherwise serve the overall public interest. State law does not currently address advertising by gas companies, but we have historically applied the same standard there.

(Id. at 5-6). The Commission recognized that the Rules Governing Promotional Allowances permit utilities to advertise jointly with others, but observed that the advertisements at issue in the *VNG* case did not satisfy the requirements of Code § 56-235.2 because they did not “solely promote the public interest, conservation or more efficient use of energy.” The Commission concluded that the *VNG* advertisements were targeted at new potential natural gas loads and provided little information about efficiency or gas conservation:

The plain thrust of the advertisement is to increase the Company’s natural gas load, not to “solely” promote the public interest, conservation, or more efficient use of energy.

This and other *VNG* advertisements offered as typical advertisements for the EEH and QGC programs do not apprise the public about how natural gas can be conserved or what specific energy efficient measures existing homeowners may undertake to conserve their gas usage.

Order at 7.

The Commission declined to include the expenses associated with the programs for *VNG*. The examples offered as typical of the advertisements at issue in the pending case are attached hereto as Appendix 2, and are no different than those offered in the *VNG* case. These ads also appear intended to increase the Company’s gas load, and not to solely promote the public interest, conservation or more efficient use of energy. Therefore, the expenses associated with the Company’s cooperative advertising program should be disallowed.

7. Common Cents Program

Staff also disallowed expenses related to the Company's Common Cents Program. (Ex. RWT-35, at 19; Ex. RWT-37, Schedule A to Statements II and III Revised, Adjustment 23). The program was approved by the Commission in *Application of Commonwealth Gas Services, Inc.*, Case No. PUE940042, 1995 S.C.C. Ann. Rep. 307. The program allowed the Company to offer rebates to customers purchasing high efficiency natural gas equipment. (*Id.*). Company witness Blair testified that the Company through its Common Cents Program successfully promoted the benefits of energy efficiency leading to its QGC program participants boosting sales of high efficiency equipment and appliances. (Ex. JRB-60, at 6).

The duration of the program was from May 1, 1995 through May 1, 1997. The Common Cents Program thus was a pilot program that ended during the test year and the Company has not proposed to make the program or a similar program permanent. (Ex. RWT-35, at 19). The rate year in this case began October 1997, therefore, the Company will not incur charges related to the Common Cents Program in the rate year and Staff accordingly eliminated all test year charges related to the program. The costs associated with the program which Staff proposes to eliminate are \$114,803. (*Id.*).

The Company asserts that it only filed its final report on the program in November of 1997. Its customers have expressed an interest in a new program, but the Company continues to evaluate its merits. (Tr. 869; Ex. JRB-60, at 8). The Company, however, advised that it intends to seek approval of a permanent program and Company witness Blair testified that the Company "anticipates filing a modified program with the Commission in 1998." (Ex. JRB-60, at 8; Tr. 881). It is the Company's opinion that it is likely to incur additional expenses related to the program in the future.

On May 15, 1998, the Company filed another general rate case ("the 1998 case") based on a twelve month test period ending December 31, 1997. The rates approved in this case will therefore only be in effect through the end of the suspension period in the 1998 case, and consequently rates in this case need not capture costs that may not be incurred until the rate year in the 1998 case. Moreover, the Company did not offer evidence to demonstrate that future expenses associated with the program are reasonably known and certain in the rate year in this case. I therefore support Staff's proposal to remove the test year costs from rates established in this case.

RATE BASE

8. Rate Base Update

In its application, the Company projected its test year rate base through September 1997 using budgeted additions for the period January 1997 through September 1997. (Ex. JES-20, at 3; Application, Schedule 13). The Company estimated its rate base to be \$255,589,937. (*Id.*). Staff updated rate base to reflect actual per books levels as of September 30, 1997. (Tr. 658). Mr. Taylor's revised rate base was \$240,698,395. (Ex. RWT-37, Statement III, Revised). In rebuttal testimony, Company witness Skirtich updated rate base through December 31, 1997. The

Company's December 31, 1997 rate base is \$251,076,405. (Ex. JES-63, at 2, Attachment 10; Tr. 896).

Staff opposes the further update recommended by the Company largely because the Staff did not have the opportunity to verify the updated rate base. (Tr. 768). Mr. Taylor acknowledged that the Company provided general ledger pages for October, November, and December 1997, and further that "the Commission has allowed in the past the Company to update rate base past the hearing. . .". (Tr. 767).

The Company testified that the increased level of rate base was necessary to meet customer growth and to replace aging pipes. The Company asserts that updating rate base to the December 31, 1997 level is the most current and therefore most accurate snapshot of rate base given current economic conditions.

Certainly, the impact on revenue requirement is significant. The variance between Staff and Company rate base impacts the revenue requirement by \$588,425. (Ex. JFR-59, at 9-10). In the Company's 1993 case, the Commission updated rate base beyond the date of the Staff's audit to balance the interests of the Company and the ratepayer. There the Company had offered substantial evidence, and the Commission based its decision on "the unusual level of plant addition experienced by the Company in the rate year due in part to the aggressive Lynchburg remediation program." *Application of Commonwealth Gas Service, Inc.*, Case No. PUE920037, 1993 S.C.C. Ann. Rep. 262, 263. The Commission went on to emphasize that "[t]his decision therefore will not establish a new precedent for evaluating the appropriate rate base to use for ratemaking." (*Id.*). Therefore, the Commission's decision in that case is not sufficient to justify updating rate base beyond the Staff audit in the pending case. Moreover, as already noted, the Company has a 1998 general rate case based on a twelve-month test period ending December 31, 1997 pending. Staff urges the Commission to incorporate any further updates to rate base in that case.

The Company argues on brief that it would be unfair to require it to forego rate recovery of over \$10 million worth of plant which the Company installed between September and December of 1997 until rates go into effect in the 1998 case. (Brief at 33-34; Tr. 897). The Company asserts that it has incurred these costs, customers currently are receiving the benefits, and therefore Columbia should be compensated now rather than later. (*Id.*). Yet, absent evidence to support the extraordinary relief afforded the Company in the prior case, the 1998 case will allow the Company adequate relief.

Finally, although the Company provided Staff with the revenue adjustment reflecting new customers as of December 31, 1997, the effect on revenue is not included in this record. (Tr. 767). It would be improper to update rate base without reflecting the increase in revenue corresponding to the customer growth that caused significant levels of the plant to be added. I find Staff's rate base as of September 30, 1997 to be reasonable for use in this case.

CAPITAL STRUCTURE AND RATE OF RETURN

9. Capital Structure

The Company proposes using the Columbia Energy Group capital structure for developing the rate of return in this case. (Ex. JBD-50, at 2). Company witness Deegan, however, recommends that the Commission adopt the actual capital structure adjusted to remove the effects of bankruptcy. (*Id.*; Ex. JBD-14, Schedule 3). Her adjustment attempts to remove the after tax impact (loss) of the Producer Settlement on capital structure by adding \$380 million to the equity balance and decreasing debt by \$380 million. (*Id.*).

Staff agrees that it's time to resume use of the CEG capital structure but disagrees with the date upon which the capital structure is measured and the Company's adjustment to remove the effect of the bankruptcy on the equity ratio in the capital structure. Staff witness Oliver proposes using the actual CEG capital structure as of September 30, 1997, without adjustment. (Ex. LTO-23, at 5-8). Mr. Oliver testified that the later capital structure is representative of those in the gas industry. (Ex. LTO-31). Mr. Oliver also testified that the impact of the bankruptcy on the CEG capital structure was diminishing, and he concluded that the actual equity ratio as of September 30, 1997 was appropriate. The CEG equity ratio in Mr. Oliver's capital structure is 45.17%. (Ex. LTO-29). The capital structures proposed by Staff and the Company are as follows:

Staff's Recommended Columbia Energy Group, Inc. Capital Structure September 30, 1997			Company's Recommended Columbia Energy Group, Inc. Capital Structure December 31, 1996, Adjusted		
<u>Component</u>	<u>Net Amount Outstanding (000's)</u>	<u>Weight (%)</u>	<u>Component</u>	<u>Net Amount Outstanding (000's)</u>	<u>Weight (%)</u>
Short-Term Debt	\$ 73,381	1.924%	Short-Term Debt	\$ 107,900	2.9%
Long-Term Debt	1,982,021	51.962%	Long-Term Debt	1,624,600	43.9%
Common Equity	1,723,000	45.171%	Common Equity	1,933,600	52.2%
Investment Tax Credits	36,000	0.944%	Investment Tax Credits	37,100	1.0%
Total Capitalization	\$3,814,402	100.001%	Total Capitalization	\$3,703,200	100.00%

Exhibits LTO-29, at 1; JBD-14, Schedule 3.

Staff thus opposes the Company's proposed capital structure, observing that if the Company's proposed adjustments are made to the more current September 30, 1997 CEG capital structure, the resulting equity ratio would be 54.33%, an equity ratio closer to a AA- rated gas distribution company. (Ex. LTO-28, at 4).

Mr. Oliver testified that the parent capital structure was used in a number of rate cases prior to the bankruptcy.

The logic was that the parent, CEG, was the entity in the financial markets raising capital. Furthermore, the allocation of capital funds to CVA was at

the discretion of management, and, therefore, could take the form of debt or equity, making CVA's capitalization ratios also at the discretion of management and not necessarily appropriate for ratemaking.

(Id.). In each of the last two rate cases, however, Staff recommended, and the Commission approved, the use of the consolidated Columbia Distribution Companies ("CDC") capital structure because it was more in line with other gas distribution utilities and the bankruptcy of the parent significantly affected its capital structure. (Id.). Here, Staff supports the return to the use of the actual parent capital structure because it provides a factual basis for the capital structure ratios as opposed to a hypothetical capital structure. Staff believes there has been sufficient capitalization ratio stability after emerging from bankruptcy, and the actual capital structure ratios are in line with ratios of other independent gas distribution utilities.

The equity ratio approved in the last rate case was 52.48% based on the consolidated CDC capital structure. (Ex. LTO-34). The equity ratio used in the Company's last AIF was 51.8% (Ex. LTO-33). The average equity ratio for Staff's sixteen company comparable group for the years 1996 through 2001 is 52.8%. Mr. Oliver's five company comparable group yielded an average equity ratio of 49.3% for the same period. (Ex. LTO-32). Dr. Haltiner, who testified on behalf of the Company, had a nine company comparable group. The average equity ratio for the years 1996 through 2001 for his group was 52.7%. (Ex. JRH-48; Tr. 593). Staff's proposed equity ratio of 45.1% still appears out of line relevant to those points of comparison.

Exhibit JBD-58 Confidential also shows the consolidated CDC capital structure as of December 31, 1996 and December 31, 1997, the actual CEG capital structure, and the capital structure for Columbia as of those same dates. This schedule reflects actual capital structures including the per books total capitalization and the regulatory adjustments reflecting short-term debt and investment tax credits. (Tr. 851). The CDC and Columbia regulatory capital structures contain equity ratios equal to or higher than that proposed by the Company for use in this case. (Ex. JBD-58 Confidential).

The Company argues that the effects of the bankruptcy still result in a substantial departure from the equity ratios of comparable gas distribution companies, and therefore, an adjustment is necessary. (Ex. JRH-48, at 9). The actual capital structures contained in Exhibit 58 Confidential show an upward movement in the equity ratios for Columbia, CDC and CEG. CEG has been continuing to build equity since emerging from bankruptcy. (Ex. LTO-28, at 5). Dr. Haltiner testified that the Company has not reached capitalization stability yet. (Ex. JRH-48, at 9).

The Commission has long held that a capital structure "should be representative of the Company's actual capital structure during the period rates set herein will be in effect." *Application of Roanoke Gas Company*, Case No. PUE920017, 1992 S.C.C. Ann. Rep. 324, 326. To that end, the Commission considers the current mix of capital which supports a company's rate base. Staff's more current September 30, 1997 CEG capital structure is more representative of the capital structure which can be expected to be in effect during the short period that rates approved in this case will be in effect. I continue, however, to be concerned with the low equity ratio. The Commission has adjusted the cost of equity in appropriate circumstances to reflect an equity ratio

that is lower, or higher, than a comparable industry group. Such an adjustment is appropriate in this case, and is discussed below.

10. Short-term Debt

Staff proposes to use CEG's 12-month daily average actual short-term debt balances for the period ending September 30, 1997. Staff proposed to use a three-month average of commercial paper rates reported by the Federal Reserve as the proxy for the cost of the Company's short-term debt. (Ex. LTO-28, at 6, 8-9).

Company witness Deegan proposes to use short-term debt balances less temporary investment balances in the Columbia Energy Group Money Pool. (Ex. JBD-50, at 12-13; Tr. 842-846). She also proposes to use a net Money Pool cost rate. (*Id.*). Initially on cross-examination Ms. Deegan had difficulty explaining why investment should be netted against borrowings and why the respective interest rates differed. (Tr. 830-34). However, on redirect examination Ms. Deegan explained that the Columbia Energy Group Money Pool is an internal financing mechanism that uses subsidiary deposits to fund other subsidiary borrowing needs. (Tr. 842). Ms. Deegan offered an exhibit entitled Columbia Energy Group Money Pool Transaction Flow which illustrates how the Money Pool operates in connection with parent and subsidiary borrowing and investment activities. (Tr. 843; Ex. JBD-53). She explained that the subsidiaries may go to the Money Pool with short-term investments and for borrowing. CEG may deposit funds into the Money Pool and may withdraw funds from the Money Pool only if there is an investment balance in the Money Pool, otherwise CEG must borrow short-term debt externally from the capital markets. The Money Pool rate is a composite of the parent's short-term debt rate and the investment rate of the Money Pool. (Tr. 844). Ms. Deegan testified that short-term debt costs and balances alone do not accurately reflect the short-term financing of the Company. The Company continues to propose use of the net effect of short-term borrowings and short-term investment in the capital structure as opposed to short-term debt balance and costs alone.

The Commission has historically looked to short-term debt vehicles in the market as proxies for the cost of that debt in the capital structure. It reflects the current cost of short-term borrowings in the market, and is appropriate for use in this case. Staff's adjustment is reasonable. Investments can be, and are, accounted for separate from the capital structure.

11. Long-term Debt

Staff and the Company agree that CEG's cost of long-term debt is appropriate for use in determining the cost of capital for Columbia. (Exs. LTO-28, at 9-11 and JBD-14, at 10). There is also no dispute that the high cost debt held before the bankruptcy was refunded. However, Mr. Oliver recommends using the cost of debt at September 30, 1997 including only the unamortized issuance costs of approximately \$21 million. (Ex. LTO-29, Schedule 3, Corrected at 1 of 3). Mr. Oliver computed the cost rate for long-term debt at 7.186%. (Tr. at 561-63; Ex. LTO-29, Schedule 3 - Corrected).

The Company included issuance and refunding costs in its calculation of the weighted average rate of CEG long-term debt. (Ex. JBD-14, at 11). Company witness Deegan's long-term

debt cost rate is 7.52%. (Ex. JBD-14, Attachment 5). That rate includes the weighted average coupon rate of debt of 7.02% with three adjustments. The first adjustment reflects one-half of the \$88.2 million, or \$44.1 million, for the estimated loss in net present value to holders of certain high cost medium-term notes (Id. at 12-13) that were redeemed at the time of emergence from bankruptcy. The second adjustment reflects the calculated call premiums of \$27.8 million on certain high costs indentures (Id. at 13) that were redeemed. The third adjustment reflects the \$21 million in costs associated with issuing \$2 billion in replacement bonds. (Id. at 15).

Mr. Oliver thus agrees with the adjustment reflecting \$21 million in issuance costs, but rejects the proposed adjustments to reflect estimated losses to holders of either medium-term notes or indentures. (Tr. 562; Ex. LTO-29, Schedule 4 - Corrected). Mr. Oliver asserts that the Company did not incur any of the \$27.8 million of indenture call premiums or any of the estimated \$44.1 million (half of the \$88.2 million total) medium-term note prepayment penalties. (Tr. 571). Specifically, the Staff asserts that the Order Confirming the Third Amended Plan of Reorganization of the Columbia Gas System, Inc. dated July 27, 1995, specifically provides that there would be no distribution with regard to call premiums or prepayment penalties for either of these securities. (Ex. JBD-52, at 22).

Company witness Deegan asserts that costs were incurred as a result of paying or refunding those debt obligations. Company witness Deegan explained that as part of the resolution of the bankruptcy, Columbia paid over \$2 billion to the holders of debt, both for repayment of principal and post-petition interest. (Ex. JBD-14, at 11). The Company argues that as a result of the refunding and the issuance of new debt, Columbia customers will receive annual benefits due to lower costs of debt. The Company therefore argues that it is appropriate for customers to bear some of the cost of achieving those benefits.

Refunding the outstanding debt benefits Columbia's customers, but the Company acknowledges that it did not incur call premiums or prepayment penalties in refunding the high cost medium-term notes (\$44.1 million) or indentures (\$27.8 million). Expenses were incurred in refunding such debt. Ms. Deegan, however, testified that as part of the settlement, the creditors gave up their claims for redemption premiums in exchange for "a very generous interest on interest offer." (Tr. 816). Hence, the cost to refund the debt was "very generous interest on interest" paid pursuant to an agreement to resolve the bankruptcy, not the typical refunding costs incorporated into debt costs.

The Commission has clearly held that bankruptcy costs should not be reflected in rates paid by Virginia customers. *Commonwealth Gas Services, Inc.*, Case No. PUE920037, 1993 S.C.C. Ann. Rep. 262, 264. I find that Virginia ratepayers should not bear the cost of the "generous. . . offer" made to and accepted by the bankruptcy debtors, and I reject both the \$44.1 million adjustment for medium-term notes and the \$27.8 million adjustment for indentures.

12. Cost of Equity

In this case, the cost of equity did not generate a heated debate. Staff and the Company used similar methodologies and similar data in calculating their recommendation for a reasonable return on equity. Mr. Oliver conducted discounted cash flow ("DCF"), risk premium, and capital asset

pricing (“CAPM”) analyses. (Ex. LTO-28). He proposes a range of 10.00% to 11.00%. (Ex. LTO-28, at 1). Company witness Haltiner also utilized DCF and CAPM analyses and proposes a range of 10.5% to 11.5%. Dr. Haltiner updated his analysis in his rebuttal testimony, but his results yielded generally the same range recommended in his direct testimony. (Ex. JRH-48, at 1).

Both Company and Staff witnesses used an average price and a prospective dividend yield in their DCF model. They agree that longer maturity risk-free rates should be used in the CAPM mechanism. They used the same source of risk estimates. They used the same Ibbotson long-term risk premium on common equity over the income portion of treasury bonds. (Tr. 794).

The difference between Mr. Oliver’s and Dr. Haltiner’s recommendations arises from their DCF calculations. Dr. Haltiner placed more emphasis on his projections of earnings growth. He testified that since dividend payout ratios of gas distribution companies have been declining, the rate in the DCF model would result in a biased estimate. (Ex. JRH-48, at 4). Mr. Oliver places more emphasis on dividend growth data than Dr. Haltiner. (Tr. 794). Mr. Oliver testified that the DCF methodology incorporates estimates of future cash flow to security holders and therefore the best measure of growth is expected growth in dividends. (Tr. 611, 617-18).

It is refreshing to have a utility witness support a reasonable recommendation for an appropriate return on equity. Certainly, differences in opinion and emphasis often arise and should be debated, but on occasion utility applicants have been known to propose such extraordinary returns that the recommendation warrants little weight. Here, however, the methodologies and recommendations of Mr. Oliver and Dr. Haltiner overlap. The entire range recommended in this case is 10% to 11.5%. Both earnings growth and growth in dividends are important considerations in the DCF calculation. Therefore, I find that a 100 basis point range of 10.25% to 11.25% is an appropriate starting point in this case and is supported by the record.

As discussed with regard to capital structure, however, I also find that a low equity ratio requires a further adjustment to the return on equity. The Commission has approved financial risk adjustments to recognize the financial risk associated with an equity ratio less than that of an average gas distribution company. *Application of Roanoke Gas Company*, Case No. PUE890055, 1990 S.C.C. Ann. Rep. 291, 293. The Commission has also approved downward adjustments to recognize an equity ratio higher than an average gas distribution company. *Application of Virginia Natural Gas, Inc.*, Case No. PUE960227, Final Order (April 27, 1998). In that case, the Commission adjusted the cost of equity downward by 30 points to account for a difference in equity ratios of 9% to 13%. Thus the Commission has adjusted for capitalization ratios that vary significantly from the average company.

Financial risk increases with the use of debt and the Commission has established the size of the adjustment to the return on equity based on the difference between the equity component in the capital structure of the applicant and that for the proxy group. As detailed above, the equity ratio in the consolidated capital structure of CEG as of September 30, 1997, is 45.17%. The equity ratios previously approved for Columbia, those of the CDC group, and those of the comparable companies included in Staff and Company’s analyses range from 49% to 53%. I find that a 25 basis point upward adjustment properly recognizes the higher risk associated with the lower equity ratio.

The Commission recently approved a common equity estimate range of 10.4% to 11.4% for Virginia Natural Gas. *Application of Virginia Natural Gas Company*, Case No. PUE960227, Final Order (April 27, 1998). The Commission approved a cost of equity range of 10.7% to 11.7% for Roanoke Gas Company. *Application of Roanoke Gas Company*, Case No. PUE960304, Final Order (August 6, 1998). Hence, a return on equity of 10.5% to 11.5%, with rates based on 11%, the midpoint, is supported by the record herein and consistent with the returns approved by the Commission for other Virginia gas distribution companies.

REVENUE REQUIREMENT

A rate of return statement is attached hereto as Appendix 4. Based upon my resolution of the issues discussed above, the agreement of the Company and Staff and parties hereto of accounting adjustments not in controversy, I find that the Company's revenue requirement is as follows:

Adjusted Net Operating Income per Taylor Statement II, Revised (Ex. RWT-37)	\$ 20,256,867
Effect of Staff's Change in Capital Structure ¹	(53,551)
Effect of Change to Uncollectible Expense	(30,778)
Effect of Change to Environmental Remediation	(58,022)
Effect of Change to Competitive Activities	(21,702)
Effect of Change to Office Furniture	(54,236)
Effect of Change to Restructuring Charges	(321,064)
Effect of Change to Consolidated Tax Savings	<u>(1,018,511)</u>
Adjusted Operating Income Per Examiner	<u>\$ 18,699,003</u>
 Rate Base per Taylor Statement II Revised (Ex. RWT-37)	 \$240,698,395
To adjust for change in Cash Working Capital	<u>(11,014)</u>
Rate Base per Examiner	\$240,709,409
Overall cost of capital with 11% ROE	<u>8.90%</u>
Required Income	\$21,416,294
Adjusted Operating Income per Examiner	<u>18,699,003</u>
Net Required Increase	\$2,717,291
Revenue Conversion Factor	<u>.629483</u>
Gross Revenue Increase	<u>\$4,313,509</u>

¹At the hearing, Mr. Oliver revised his recommendation on the appropriate capital structure, but the effect of that change was not included in Exhibit RWT-37, Statement II Revised. (Tr. 563).

REVENUE APPORTIONMENT, COST ALLOCATION, AND RATE DESIGN

The parties agreed to the allocation of the proposed increase in revenues according to the percentages set forth in Ex. REH-27, Attachment 1 Revised. The parties also agreed that if the Commission's decision in this case results in a lower revenue requirement than requested by the Company, the customer charge originally proposed by the Company for the residential class should be proportionally lower, and further that it should be lowered in increments no smaller than \$.05 per month for residential customers. (Tr. 427, 525). That recommended revenue apportionment includes Staff witness Lacy's proposed additional increase for Rate Schedules TS1 and TS2 to maintain the equilibrium between the Company's rate schedules. The agreed allocation is attached hereto as Appendix 5.

13. Propane Service

Columbia currently provides propane distribution service pursuant to a metered propane service ("MPS") rate schedule. The service is available to customers for whom natural gas services not immediately available. (Ex. JRB-60, at 9). Rates under the MPS schedule are the same as rates for residential natural gas service. (Ex. CML-24, at 10).

In the Company's last case, the Commission found that Columbia was not converting its MPS customers to natural gas within a reasonable period of time, and accordingly, a moratorium was placed on the addition of MPS customers. *Application of Commonwealth Gas Services, Inc.*, Case No. PUE950033, 1996 S.C.C. Ann. Rep. 268. The Commission also required that all conversions from propane to natural gas be made within two years. (*Id.*). In this case, Columbia now asks the Commission to lift the moratorium because it has created a hardship for the Company. The Company argues that the moratorium does not serve the public interest. To the contrary the Company argues that the MPS schedule is beneficial because the Company has a larger customer base due to its MPS offering. (Ex. JRB-60, at 10). Company witness Blair argues that lifting the moratorium will provide Columbia with another vehicle to provide service to its customers and thereby serve the public interest. (*Id.* at 11).

The Company also proposes a new rate schedule for propane delivery service ("PDS"). The PDS rate was developed based on the full cost of propane. Under the new rate schedule, customers would be charged the full cost of propane rather than the subsidized rate set forth under rate schedule MPS. The Company proposes to serve PDS customers through an underground distribution pipe system just like its natural gas customers. (Ex. JRB-60, at 8-9). As proposed, the new PDS rate schedule does not require conversion to natural gas service within two years. (*Id.*). Mr. Blair, however, testified that conversion would occur within a reasonable time subject to the Company's economic criteria. (*Id.*).

Mr. Scott Camp testified as a public witness at the hearing. Mr. Camp is the developer of a 2,000 acre subdivision in southern Chesterfield County called Chesdin Landing. He testified that 90% of the residents in the subdivision desire natural gas service, but none is presently available. He urged the Commission to allow Columbia to install a tank farm to serve Chesdin Landing under the new rate schedule. He further testified that no one objected to higher prices for the propane service until natural gas service is available in the subdivision in the near future. (Tr. 414-415).

Company witness Blair testified that customers on average will incur lower costs under the PDS schedule than they would if they individually acquired propane since the Company can purchase propane at a cost approximately 30% less than the retail price. (Tr. 877).

Staff supports the establishment of rate schedule PDS. However, Ms. Lacy supports implementation under several conditions. She recommends that availability should be limited to customers in areas where natural gas is planned and approved to be available in the near future; that the existing MPS rate schedule should be closed to new customers; and that propane suppliers should be selected by competitive bid. (Ex. CML-24, at 10).

The Company objects to closing the MPS schedule to new customers. It asserts that the MPS and PDS schedules offer two different services at different rates. The Company also rejects Ms. Lacy's recommendation that a time limit be imposed on PDS. With the time limit, the Company argues, the two propane rate schedules would be too similar and cause customer confusion. Finally, the Company agreed to acquire propane through a competitive bidding process. Mr. Blair testified that the Company had intended to do just that. (Tr. 891-894).

I agree with Ms. Lacy that Columbia's fundamental business is to provide natural gas service. Ms. Lacy observed that without limitations the Company has taken seven to eight years to convert MPS customers to natural gas, and some of those customers still remain on propane. (Tr. at 884-85). Thus Columbia's history under the MPS schedule indicates that it allowed subsidized propane service to continue well beyond the temporary time periods anticipated when the schedule was implemented. I therefore also agree that Columbia should be required to convert its propane customers to natural gas within a reasonable period of time. Staff recommends two years. I support that recommendation.

Moreover, the PDS rate which is designed to recover the costs of the propane service is preferable to the subsidized rate in the MPS schedule. The Company offered no convincing evidence to support continuation of a subsidized propane rate. With the new PDS schedule modified to include a specific conversion period, there is no need to continue the MPS schedule and it should be closed to new customers.

14. Air Conditioning Service

The Company proposed a new rate schedule for air conditioning service ("ACS"). Staff supports that new schedule, and the Company agrees with Staff's recommendation to move existing air conditioning customers served under Rate Schedule SCS to the new schedule. (Ex. CML-24, at 12-13; Ex. JRB-60, at 11-12).

15. Natural Gas Vehicle Rate Schedule

Staff recommends that the Company submit a report on its two-year experimental program for natural gas vehicle service. That program has ended, and the Company agreed with Staff's recommendation to submit a report and make its recommendations as to whether the program should be discontinued or made permanent. (Ex. CML-24, at 16; Ex. JRB-60, at 12).

16. Line Extension Policy

Staff reviewed information from the Company on line extension costs, tax costs, and the amounts refunded to customers for 1995, 1996, and 1997. (Ex. CML-24, at 25 and Schedule 12). Ms. Lacy determined that the Company refunds substantial amounts to residential customers. Staff concluded that the Company's current line extension calculations for residential customers may not attribute sufficient anticipated revenues to the line extension, resulting in higher than necessary customer deposit requirements and significant total refund amounts. Ms. Lacy therefore recommended that the Company's line extension calculation for residential customers include three to five years of anticipated revenues rather than the two years currently provided.

Company witness Blair testified that the Company works with developers to project the total amount of new building construction that will occur in the first two years after a new line is installed to estimate the expected revenue over that two-year period. The Company argues that the Staff's proposed change is unjustified and unnecessary. It asserts that estimating revenues for a three to five year period is too speculative. (Ex. JRB-60, at 13-14). The Company argues that such speculative estimates could lead to unjustified line extensions, and thus to higher rates to all customers. (*Id.*). I agree. The Company has difficulty projecting revenues two years ahead. At this point, estimating revenues for up to five years is speculative. The Company's line extension policy on customer deposits should not be changed in this case, with the exception of an adjustment for taxes. Ms. Lacy testified, and the Company agreed that deposits for line extensions should include a gross-up for federal income taxes. (Tr. at 891).

17. Meter Readings

The Company proposed to change its tariff to allow it to elect to calculate initial or final meter readings unless the customer requests or provides the Company with an actual meter reading. Staff objected to that change. Ms. Lacy, however, testified that she would support allowing the customer to request a calculated reading for the initial or final bill. (Ex. CML-24, at 23). The Company agreed to that modification. (Tr. at 461-62). Ms. Lacy's recommendation is reasonable.

18. Reconnection Charge

The Company also proposed to require customers to pay actual reconnection costs if such costs exceed \$30. Staff testified that the Company's proposed tariff language was intended to address an unusual connection but the proposed language was too broad and would promote higher charges for any reconnection that the Company determines costs more than \$30. Therefore, Staff recommends that the tariff explicitly state that the actual cost of a reconnection will be charged if the reconnection must be made at the main connection. (Ex. CML-24, at 21). The Company agreed with Staff's recommendation to limit the tariff language. Staff's modified language is reasonable and should be adopted.

19. **Customer Deposit Installments**

The Company proposes to change the minimum amount which a customer may pay over three installments from \$40 to \$100. Staff also recommends the minimum deposit which would qualify for a three-month installment payment be increased, but only to \$60. (Ex. CML-24, at 22).

The Commission's current policy on customer deposits was initially adopted in 1977. *Commonwealth of Virginia, ex rel. State Corporation Commission, Ex Parte, in re: Investigation to determine the reasonableness of certain practices and charges by public utilities*, Case No. 19589, 1977 S.C.C. Ann. Rep. 124. The policy was later revised in 1983, but the minimum deposit for which installment payments were allowed was not changed. *Commonwealth of Virginia, ex rel. State Corporation Commission, Ex Parte, in re: Adoption of a Revised Rule Governing Utility Customer Deposit Requirements*, Case No. PUE820073, 1983 S.C.C. Ann. Rep. 394. The rule provides:

Whenever a utility requires a deposit from any residential customer, said customer shall be permitted to pay it in three consecutive equal monthly installments whenever the total amount of the required deposit exceeds the sum of forty dollars (\$40.00). Provided, however, that each utility shall have the discretion to allow payment of any deposit (more or less than the \$40.00 total) over a longer period of time to avoid undue hardship.

(*Id.* at 395). Although some adjustment in the minimum deposit amount from installment payments may be appropriate to reflect price and rate changes, the Commission's rules in that regard have not been changed. Therefore, I cannot recommend any change in the Company's tariff on deposits payable in installments.

20. **Charges for Copies of Tariffs and Annual Subscriptions for Revisions**

The Company also proposes to add a \$50 charge for a copy of its complete gas tariff, and another \$50 charge for an annual subscription for gas tariff revisions. The charges would be assessed on marketers and other non-customers. Staff generally supports the establishment of those charges; however, Staff believes the charges should apply only to non-customers. Moreover, Staff witness Lacy testified that a marketer involved in the Commonwealth Choice Program becomes a customer by receiving service under the Aggregation Service Rate Schedule. Therefore, marketers participating in the Commonwealth Choice Program should not be assessed the charge. (Ex. CML-24, at 21). I find the proposed charges, as clarified by Ms. Lacy to be reasonable.

21. **Commonwealth Choice Program – Stranded Cost Recovery Charge**

On September 30, 1997, the Commission approved the Company's Commonwealth Choice Program for residential and small general service customers in a limited market area. *Application of Commonwealth Gas Services, Inc.*, Case No. PUE970455, Order Approving Commonwealth Choice Program (September 30, 1997) ("Commonwealth Choice Program Order"). The program was approved for a two-year period and was designed to provide transportation services allowing

customers to purchase gas directly from participating marketers. Gas deliveries under the program began on January 1, 1998. Within three weeks, five marketers were participating in the program. Three of those marketers had elected to nominate pipeline capacity from the Company. (Ex. CML-24, at 17).

In its application, the Company requested full recovery of anticipated stranded costs resulting from the program through a mechanism called the Stranded Cost Recovery Charge or SCRC. The Company generally defines stranded costs as investments it has made that would have been required for the Company's customers but for the transition to a competitive market. (Brief at 54). Company witness Horner specifically described stranded costs as: "upstream pipeline capacity charges that are not absorbed by assignment or mitigated by some other means." (Ex. REH-27, at 5). The Company proposed to collect the SCRC from all residential and small general service customers. (Ex. REH-18, at 9).

The Company projected the stranded costs it expected from the program. The Company proposed 2.2¢ per Mcf as an initial SCRC applicable to all residential and small general service customers. It assumed that no marketers would elect to receive pipeline capacity assignments from Columbia and that market penetration in the program would be 20% of residential customers and 40% of commercial customers. (Ex. CML-24, at 18; Tr. 463-64). The Company also assumed normal weather. (Tr. 469). The Company did not include the effect of any mitigation measures or the effect of load growth in the area, but the Company proposed to annually true up any SCRC that was assessed on its customers. (Exs. REH-18, at 10, CML-24, at 18; Tr. 473).

By the hearing in this phase of the case, the Company had concluded that it did not have sufficient data on stranded costs and sought deferral of a decision on an SCRC until its next case, or until it seeks to make the program permanent.

The Commission deferred its determination on the propriety of the SCRC until this phase of the case. The Company was allowed to track the costs of the program by memorandum accounting. (July 28 Scheduling Order at 9; Commonwealth Choice Program Order at 13).

Staff opposes the SCRC. Ms. Lacy testified that the proposed SCRC ignores the Company's systemwide pipeline related activities, some of which have considerably more cost significance than the small amount of capacity at issue in this program. She testified that any stranded costs arising from this program should be considered in the broader context of the Company's overall supply and demand situation. (Ex. CML-24, at 18). Ms. Lacy also testified that Columbia has constrained capacity, and therefore the Company has recently committed to significant pipeline capacity and storage contracts with an affiliate. (*Id.* at 19). Thus, the Company is seeking stranded pipeline costs while contracting to buy additional capacity. She also observed that Columbia anticipates growth in the program market area. (Tr. 466).

Staff witness Lacy added that if the Commission adopts the proposed SCRC, Staff recommends that the charge apply only to customers participating in the pilot program. Staff asserts that the Company seeks to charge customers who would not be responsible for stranded costs, if any, being incurred. Staff argues that the Company did not offer any evidence as to how ineligible and non-participating customers would benefit from the program. Ms. Lacy testified that

“the least responsible customers for stranded costs would be those residential and small commercial sales customers” not participating in the program. (Tr. 494). Further, Staff urges the Commission to require that the Company be required to pursue activities that would mitigate stranded costs such as renegotiating or eliminating contracts related to excessive pipeline capacity. Moreover, Staff does not believe that the Company should be able to recover any stranded cost for new pipeline and storage capacity contracts entered into in 1996 and beyond. (Ex. CML-24, at 20). Staff added that any decision regarding stranded cost recovery in this case should not be viewed as generally applicable to questions about stranded cost recovery for other Virginia utilities. Specifically, the charge in this case is associated with a specific experimental program proposed by the Company itself and does not arise from any state or federal legislative action on restructuring. (Id. at 20).

Staff asserts that there is ample evidence to demonstrate that it is inappropriate to establish an SCRC while the Company is contracting for additional capacity and experiencing growth in the market area. (Staff Brief at 36). Staff recommends that the Company continue to gather information on marketer nominations of pipeline capacity and related costs through the end of the two-year pilot program. (Ex. CML-24, at 19). Staff does not support deferring the decision on the SCRC issue until the next rate case.

The Consumer Counsel also addressed recovery of stranded costs from the Commonwealth Choice Program. Specifically, the Consumer Counsel asserts that the Commission should determine now if any stranded cost method is necessary, and if so, what recovery method should be utilized. Consumer Counsel witness Galligan testified that any recovery method should include the Company’s transportation customers because they have enjoyed the benefits of the competitive market denied to smaller customers for a number of years. (Tr. 516). Mr. Galligan recommends that the Commission “embrace the broad-sharing principle of transition costs and spread them to all customers who will benefit or who are benefiting from participating in the transportation market.” (Tr. 514-515). Mr. Galligan asserts that the residential customers who are now beginning to qualify for participation in the competitive gas acquisition market shared the transition cost responsibility in the past under the equitable sharing principle. (Tr. 516). He argues that it would be unfair to now target only those last remaining sales customers with the transition cost associated with the final step of moving to a competitive market. (Id.).

Mr. Galligan proposed that stranded costs could be recovered through a volumetric surcharge assessed on all customers purchasing their gas supply in the competitive market. (Ex. RAG-25, at 25). He testified that such a method was consistent with benefits received and with equitable sharing. He added that residential and small general service customers not participating in the program have not caused nor are they responsible for the incurrence of stranded costs. (Id.).

The Industrial Protestants also addressed the issue of stranded cost associated with the Commonwealth Choice Program. They assert that the Company should not be allowed to recover any alleged stranded costs associated with the program. They note that it is not a foregone conclusion that the Company will experience any stranded costs merely because it has implemented a pilot program. The Industrial Protestants assert that the Company has failed to present any evidence that would justify imposition of such a mechanism at this time. (Industrial Protestants’ Brief at 5). They agree with Staff witness Lacy’s position that the Commission should avoid narrowly focusing on the small amount of capacity at issue in this program while ignoring other

activities related to pipeline capacity. Moreover, they also assert that the Commission should consider measures the Company can take to mitigate potential stranded costs.

The Industrial Protestants, however, further assert that if a stranded cost mechanism is to be applied, the Company's proposal to impose the charge on all residential and small commercial customers is more reasonable than other recommendations. They argue that since the purpose of the pilot is to begin to allow residential and small commercial customers a choice of competitive gas suppliers, it is consistent with established cost allocation principles to collect any stranded costs only from those classes. (*Id.*).

Enron also participated in this case to address the SCRC. Enron witness Magruder testified that "[a]s a general matter, ... Enron supports the full recovery of net verifiable, prudently incurred and fully mitigated stranded costs for utilities that are actively pursuing opening their systems." (Tr. 904). She also supported establishing an end date beyond which stranded cost recovery should not be considered. (*Id.*). Enron supports the Company's revised recommendation to defer implementation of the SCRC. (*Id.*).

Ms. Magruder, however, argues that if an SCRC is approved, it should be assessed on all customers within the class, as proposed by the Company, or the resulting charge may be too high and create a barrier to customer choice. (Ex. KEM-64, at 3). Enron asserts that the determination and assessment of stranded costs to consumers is a critical issue in restructuring and if instituted prematurely or if it is too high, consumers may not exercise choice because a non-utility supplier cannot offer a competitive sales rate. (Enron Brief at 7).

I concur with many of the parties' observation that this record does not support a finding that any stranded costs exist for the pilot program. There was no dispute that the Company's proposed \$.022 charge did not consider upstream capacity purchased by suppliers from Columbia, lower penetration in the program than expected, warmer weather during the pilot period to date, load growth, or off-system sales. (Tr. 465-470, 485). All parties agree that any costs should be mitigated.

A decision on the proposed SCRC, however, need not be deferred. With no evidence of stranded costs and uncontested testimony of numerous factors which offset any capacity unused as a result of this program, I find that the SCRC should be rejected for the pilot program. Stranded upstream pipeline capacity costs simply do not exist when a company is contracting for additional capacity. The Company should, however, continue collecting data as recommended by Staff for the duration of the pilot program.

FINDINGS AND RECOMMENDATIONS

In conclusion, based on the evidence received herein and for the reasons set forth above, I find that:

1. The use of the test period ending December 31, 1996, is proper in this proceeding;
2. The Company's test year operating revenues, after all adjustments, were \$170,245,173;
3. The Company's test year operating revenue deductions, after all adjustments, were \$151,320,372;
4. The Company's test year net operating income and adjusted net operating income, after all adjustments, were \$18,924,801 and \$18,699,003 respectively;
5. The Company's adjusted test year rate base is \$240,709,409;
6. The Company's current rates produce a return on adjusted rate base of 7.77% and a return on equity of 8.50%;
7. The Company's current cost of equity is in a range of 10.5% to 11.5%, and the Company's rates should be established based on the midpoint of the equity range, 11.0%;
8. The Company's overall cost of capital, using the midpoint of the equity range and the capital structure found reasonable herein, is 8.90%;
9. The Company's request for an annual increase in revenues of \$7,941,578 is unjust and unreasonable because it will generate a return on rate base greater than 8.90%;
10. The Company requires \$4,313,509 in additional gross annual revenues to earn an 8.90% return on rate base;
11. The Company should file permanent rates designed to produce the additional revenues found reasonable herein using the revenue apportionment methodology agreed to by the parties and attached hereto as Appendix 5;
12. The Company should be required to refund with interest, all revenues collected under its interim rates in excess of the amount found just and reasonable herein;
13. The tariff changes discussed herein should be approved; and
14. The Company's proposed SCRC should be rejected.

In accordance with the above findings, ***I RECOMMEND*** that the Commission enter an order that:

1. ***ADOPTS*** the findings of this report;
2. ***GRANTS*** the Company an increase in gross annual revenues of \$4,313,509;
3. ***DIRECTS*** the prompt refund of all amounts collected under interim rates in excess of the rate increase found just and reasonable herein.

COMMENTS

The parties are advised that any comments (Section 12.1-31 of the Code of Virginia and Commission Rule 5:16(e)) to this Report must be filed with the Clerk of the Commission in writing, in an original and fifteen (15) copies, within fifteen (15) days from the date hereof. The mailing address to which any such filing must be sent is Document Control Center, P. O. Box 2118, Richmond, Virginia 23218. Any party filing such comments shall attach a certificate to the foot of such document certifying that copies have been mailed or delivered to all other counsel of record and to any party not represented by counsel.

Respectfully submitted,

Deborah V. Ellenberg
Chief Hearing Examiner